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Hydrogen production from biomass gasification in the oil refining industry – A system analysis

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ABSTRACT

In this paper, the global CO_2 effect of integrating different biomass gasification concepts to meet an increasing demand of hydrogen in an oil refinery is examined and presented in comparison with a conventional steam reformer. The studied refinery is a hydro skimming refinery with a future hydrogen deficit of 16,000 Nm^3/h. Three gasification concepts are considered: Entrained Flow (EF), Circulated Fluidised Bed (CFB) and Double Bed (DB). The system analysis is made with respect to global CO_2 emissions and primary energy use. The results show that if biomass is considered as an unlimited resource (i.e. sufficient biomass is considered to be available to substitute for all fossil fuels in society), biomass gasification concepts have a potential to reduce CO_2 emissions. The EF case shows the largest reduction potential. However, if biomass is considered as a limited resource (i.e. increased use of biomass at the refinery will lead to increased use of fossil fuel elsewhere in society), all concepts show an increase of CO_2 emissions. Here, the CFB gasifier shows lowest increase of CO_2 emission. The CO_2 effect of the different alternatives shows sensitivity to assumptions regarding alternative biomass user.

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1. Introduction

The oil refining industry generates large amounts of CO_2 emissions, around 150 Mt/year in EU27 (EU ETS). Today, and in the future, harder regulations (e.g. the EU ETS system and the Renewable Energy Directive) both on CO_2 emissions from the refinery process and on the refinery products will give new incentives for the oil refining industry to act towards CO_2 mitigation measures. Although energy efficiency in the refining process has improved significantly over the last decades, continuing growth in diesel demand, and demand for cleaner fuels, have resulted in higher total energy consumption in the refining process. A continuing increase of the diesel/gasoline ratio ([1–3]) in combination with harder environmental specifications and quality standards applicable to marine fuels, road fuels and fuel oils (see CONCAWE, 2008 [1] for a comprehensive review) will lead to increased hydrogen demand and most likely to increased energy consumption and CO_2 emissions. To meet the more stringent regulations on the sulphur content, significant investments in additional desulphurisation capacity, e.g. hydrogen plant capacity, will be required [4,5]. Consequently, large production of hydrogen will be needed in the future to meet the increasing demand for hydrogen in the oil refining industry [1,4,5]. Today many refineries in Europe already have a hydrogen plant; the most common technology is a steam methane reformer (SMR) that produces sufficient hydrogen to meet the on-site demand. Refineries without a hydrogen plant or refineries with fully loaded hydrogen plant capacity might most likely suffer from a deficit of hydrogen in the future. Refineries have several options for the supply of hydrogen [6]. These include: recovering hydrogen from refinery fuel gas [7], improve design on the consumer units [5], optimise the hydrogen distribution system [8–12], building a new steam reformer, producing hydrogen via gasification [13,14], or importing hydrogen from a third party.

With increasing concern for greenhouse gas emissions and growing reduction targets for CO_2 emissions, interest in sustainable solutions is rising in all sectors including the oil-demanding industries. Biomass gasification (BG) is a renewable alternative that has the potential to decrease CO_2 emissions. However, efficient energy and resource utilisation is essential. Studies by Azar et al. (2003) [15] and Wahlund et al. (2004) [16], show that biomass is most cost-effectively used for heating purposes or electricity generation. But to increase the overall efficiency, BG could be integrated in industrial processes. Fahlén et al. (2009) [17] show that integration of BG with district heating system could reduce

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Nomenclature

BG	Biomass gasification
EL	electricity
SMR	steam reformer
EF	Entrained Flow
CFB	Fluid circulated Bed
DB	Double Bed
PSA	Pressure Swing Absorption
HT-shift	High temperature shift
LT shift	Low temperature shift
DS	Dry Substance
CCS	Carbon Capture and Storage

CO_2 emissions, but the cost is highly dependent on fuel and electricity prices as well as policy instruments. Andersson (2007) [18,19,20] shows that BG integration with a pulp and paper mill has several advantages, both regarding CO_2 reduction and in an economic perspective. Also, Wetterlund et al. (2011) [21] show that biomass gasification can be economically profitable for an integrated pulp and paper mill. Furthermore, Pettersson et al. (2010) [22] have carried out system studies of black liquor gasification integrated in the pulp and paper industry.

Concerning biomass gasification in the oil refining industry, only a few studies have been found. In a study by Rodin (2008) [23] two different gasification concepts (atmospheric gasification with wood chips and atmospheric gasification with pyrolysis oil) for H_2 production in an oil refinery are compared and environmentally evaluated. The study shows that BG of pyrolysis oil requires more biomass but generates less CO_2 if biomass is considered CO_2-neutral. However, no integration with the process, or comparison with alternative H_2 production processes, was considered. Sarkar and Kumar (2009) [14] have conducted a techno-economic assessment of biohydrogen production by a thermal stand-alone gasification of whole-tree forest biomass in western Canada. Sarkar's and Kumar's shows that the production costs for a stand-alone plant at 2000 dry ton (of biomass) per day is more expensive compared to a steam methane reformer. If 500 km transportation of H_2 by pipeline is included, the costs almost double for the H_2 production with a biomass gasifier. Only with a high long-term natural gas price would this plant become competitive, or with a combination of a lower natural gas price and a carbon credit price of around €100 per ton of CO_2. The study compares hydrogen from biomass with a conventional SMR, but does not consider integration of these in an oil refinery. A more recent study by Sarkar and Kumar (2010) shows that the technology and feedstock given the lowest cost for delivery biohydrogen differs depending on the size of the gasifier [24].

Drying of the initial biomass is a very energy-consuming part of the BG process. Previously, several studies have been made to evaluate different drying concepts in the context of biomass use for BG. Andersson et al. (2006) [25] found that flue gas drying was the most attractive option for biomass drying integrated in a pulp mill. Heyne et al. (2009) [26] show that substantial energy savings can be made if drying is integrated in a BG process for SNG production. In Heyne's study the steam drying process turned out to be the most attractive option.

In this paper the different BG options for production of hydrogen are integrated in the oil refining process and evaluated with a focus on heat integration and CO_2 emissions. The refinery considered in this paper is a hydro skimming refinery with a future of minimum gasoline production and maximum production of diesel, leading to a hydrogen deficit of 16,000 m^3(n)/h. No previous studies were found that study the system integration of different biomass-based gasification in comparison with conventional hydrogen production technologies.

2. Objective and research questions

The aim of this paper is to investigate the possibility of meeting the future increased hydrogen demand in the oil refining industry by different BG technologies, and to compare the results with respect to CO_2 emissions with a conventional SMR. Since BG is a technology under development and many uncertainties remain before it will be commercially available, several BG concepts have been studied and compared. Three types of BG concepts are considered:

- Entrained Flow (EF) gasification.
- Circulated Fluidised Bed (CFB) gasifier
- Indirect Double Bed (DB) gasifier

This paper includes the whole BG chain, from biomass drying to hydrogen production.

The system analysis is made with respect to global CO_2 emissions and energy use as a first step in determining whether hydrogen production from BG is a better alternative than conventional fossil fuel-based steam reforming. In order to reach the paper's objective, the following research questions are addressed:

1. Can the excess heat from the current process and/or from the new technologies (BG or SMR) be used for heat integration between the refinery process and the new technologies?
2. What is the energy balance for the different concepts?
3. What is the CO_2 consequence of implementing a biomass gasifier for H_2 production in an oil refinery compared to a conventional SMR?

3. Overview of the study

To get an overview of the upcoming analysis, the following combinations of Scenario and Case set-ups are involved in the main analysis:

Case A: There is an excess of biomass in society		*Case B*: Biomass is a limited resource in society (marginal user of biomass is coal power plants)	
Scenario 1: Marginal producer of electricity is coal power plants	*Scenario 2*: Marginal producer of electricity is coal power plants with CCS	*Scenario 1*: Marginal producer of electricity is coal power plants	*Scenario 2*: Marginal producer of electricity is coal power plants with CCS

The following parameters are included in the sensitivity analyses

- Drying technology for CFB is changed from air drying to steam- and flue gas drying
- EF gasification temperature is changed from 1300 °C to 1500 °C
- Biomass moisture content in the CFB gasifier is increased from 10% to 20% and 30%. For the DB gasifier the biomass moisture content is increased from 10% to 17%
- The alternative biomass user is changed from coal power plants to DME producers

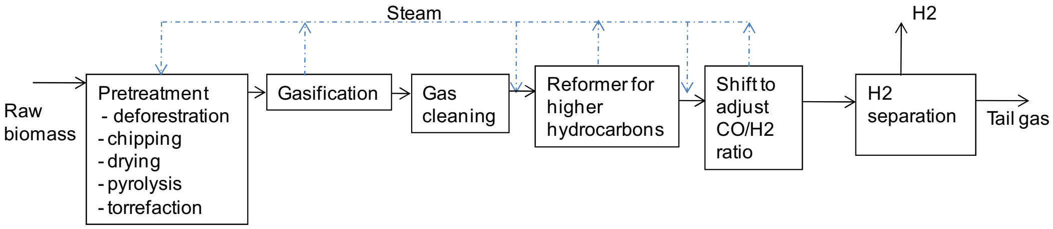

Fig. 1. Illustration of key steps in gasification to hydrogen.

4. Background – gasification of biomass

Large-scale production of synthetic gas via gasification of biomass is an emerging technology, not yet fully commercialized. In 2010, nine biomass/waste gasifiers were in operation [27]. The most promising gasification technologies for large-scale applications are bubbling and fluidized bed gasification [28]. Of the gasifiers in this category, directly heated bubbling fluidized bed BG has been the most widely demonstrated and operated over a wide range of conditions [28]. Hydrogen production from biomass via gasification involves several possible steps, commercial or under development. Typically, hydrogen production consists of the following steps: pre-treatment, gasification, gas cleaning, reforming, shift to obtain appropriate H2:CO ratio, gas separation and purification [28–31]; see Fig. 1.

5. The studied systems – boundaries, assumptions and input data

The system boundary of this paper is around the refinery industry, including the surrounding energy systems; for the BG case, this includes drying, pre-treatment, gasification, cleaning and upgrading of the syngas. All analyses are based on the assumption of the raw material being biomass with a 50% moisture content. This section includes a description of the system studied and a description of the main energy flows of a future refinery with SMR and a possible future refinery with BG.

5.1. Refinery

In this paper, the case facility is a hydro skimming refinery with a current crude oil capacity of 6 Mton/year and 0.5 Mton CO_2/year. Main process units are a crude distillation unit, a catalytic reformer unit, a light gas oil hydro treatment unit and a mild hydro cracker unit, which recently has been rebuilt to work partly on renewable feedstock (tall oil) to produce diesel. Main energy and material streams are shown in Fig. 2.

Since BG is most likely to be commercialised beyond 2020, a future situation for the refinery energy balance is used. The main assumption regarding the refinery is that the current refinery will, in the future, minimize its production of gasoline and, hence, run the reformer unit on minimum load (from current 3600 m^3/day to 1800 m^3/day). This will halve the gasoline production. The reason for this is a declining demand of gasoline and an increasing demand of diesel. The current refinery is also on its way to start a production of tall oil diesel, which includes a new process unit, a green hydrotreater unit. Due to the increased production of diesel and the new hydrotreater, the hydrogen demand in the refinery will increase. The new hydrogen plant must both replace half the production of hydrogen from the reformer unit (13,650 m^3/h)[1] and supply the increased demand in the refinery processes (2570 m^3/h), which amounts 16,220 m^3/h.

While the refinery changes the production, it is assumed that the crude oil feed will remain constant (17,400 m^3/day) and only parts of the refinery process will be affected. The product change will not only affect the hydrogen demand but also the steam and the electricity demand. The steam demand from the current boilers will increase from 62 ton/h to 79 ton/h and the electricity demand will change from 455 MWh/day to 413 MWh/day, which mainly is due to the decreased using of the reformer unit. The future total fuel demand in process heaters and boilers are 233 MW and the natural gas supply is (before integrating a SMR or a BG) 84 MW, the rest of the fuel needed (in boilers and heaters) are provided from refinery gases. Key data for the future refinery process with an SMR are given in Table 1.

5.2. System assumptions

In the evaluation of CO_2 emissions, the refinery process in combination with the different BG systems is analysed and compared to the refinery process in combination with a conventional SMR. The following assumptions are made for the analysis:

- The basis for the calculations is an H_2 production of 16,000 m^3(n) /h, which is the net consumption for a future refinery situation (~50% of the total demand).
- MP (16 bar; 280 °C) & LP (4.2 bar; 150 °C) steam is produced from excess heat from the SMR & the BGs.
- If a turbine exists at the refinery, it is assumed to be loaded to full capacity.
- Initial moisture content of the biomass is 50% for all cases.
- The tail gas from the BGs and the pyrolysis gas are used as fuel in the refinery.
- No district heating system is available.
- The current energy and material streams in the case refinery are the basis for the calculations. These are then adjusted to fit the future situation described above.

5.3. The studied BG concepts

Fig. 3 illustrates the different BG chains studied, from biomass drying to production of hydrogen. As can be seen from the figure, when the CFB and the DB gasifiers require treatment of the syngas after the gasifier to deal with tars and other hydrocarbons, the EF gasifier does not. Instead it requires pre-treatment of the fuel which has to be in small particles or a liquid to have time to react when it is blown trough the reactor at high speed. The temperature out from the EF gasifier is very high and this stream has to be quenched to 850 °C before going to the shift reaction.

The CFB gasifier has been combined with a high temperature filter and a reformer with catalyst material to react methane and hydrocarbons to $H_2 + CO$. Hot gas cleaning is considered for the EF and the CFB cases. Here alkali components and halogens are removed using reagents at 350 °C [29]. After the DB gasifier a filter

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[1] The reformer unit produces hydrogen as a by-product, which currently is enough to meet the hydrogen demand.

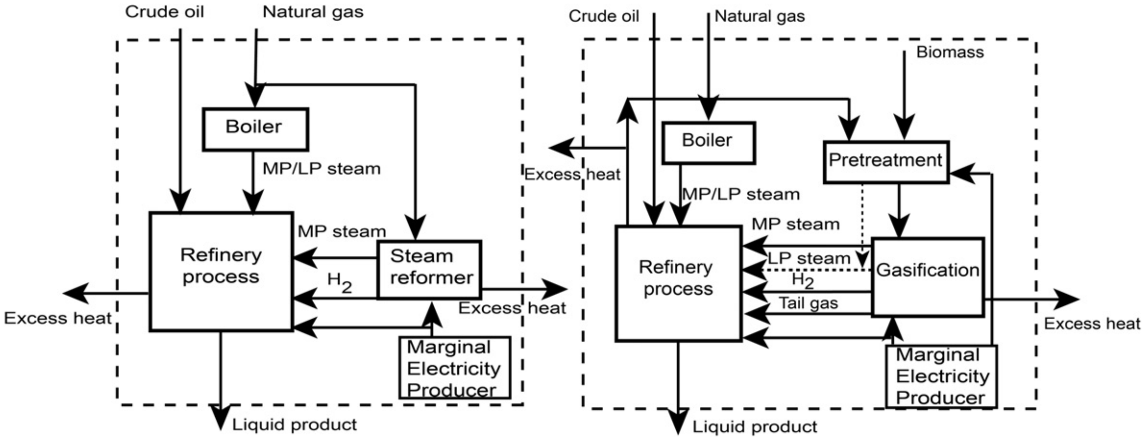

Fig. 2. Main energy and material streams in a refinery with an SMR (at left) and with a gasification plant (at right), covering the increased H_2 demand.

Table 1
Key data for the hydro skimming refinery used in this study in 2030 (future refinery with conventional steam reforming).

Crude oil	Mton/year	6
Electricity, total consumption	MW	19
Steam demand, MP, LP	MW	51
Natural gas to SMR	MW	60
Natural gas to boilers and heaters	MW	80
Biomass used as fuel	MW	0

and a RME scrubber are used to remove tar and the tar-rich RME bleed is fed to the combustor along with fly ash. A solvent absorption unit can be used to bring the sulphur content down to below 0.01 ppm [29]. Since the syngas from the DB gasifier contains higher yield of methane, compared to the syngas from the other two gasifiers, an SMR is used to maximize the H_2 and CO_2 yield.

The common steps for all BG processes and the SMR process in this paper are the upgrading steps (the dual shift reaction and the PSA unit). These steps are mainly constructed and built upon results from Hamelinck and Faaij [29]. The purpose of the dual shift reactor is to increase the H_2:CO ratio, which should be high to favour hydrogen production [31]. CO and H_2 are subsequently separated in the PSA unit, in a two-step approach, following the description in [29]. In the first step CO_2 and H_2 are separated and in the following step all remaining gases, except 84% of the hydrogen, are removed. By recycling 80% of the gases, the overall efficiency can be increased to over 90% [29]. More detailed information of the upgrading streams for each process can be found in Appendix.

Mass and energy balances for the gasifiers are simulated and provided by Eva Larsson at TPS (2010) [32]. Fig. 4 shows the streams included in these calculations.

5.3.1. Biomass feedstock

The biomass used as feedstock in the DB and CFB gasifiers consists of a mixture of wood, bark and waste wood and an original moisture content of 50% before drying. Due to the difficulties of feeding biomass to the EF gasifier, torrefied biomass and pyrolysis oil have been used in these gasifiers. The compositions of the feedstocks are defined in Table 2.

5.3.2. Drying technologies

Three types of dryers were considered for the drying of the incoming biomass:

- *Air drier (Band dryer):* In a band dryer the wet biomass is carried through the dryer on a band, in which the air is blown through the wet biomass from either above or below. This dryer is suitable for use of excess heat and has low electricity demand [33].
- *Steam dryer:* In the steam dryer, medium pressure steam is used as heat source to evaporate the moisture content in the biomass. In the steam drying process, the evaporated moisture is separated from the circulated steam and condensed; heat is thereby regenerated and steam at lower pressure is leaving the dryer.
- *Flue gas dryer:* In a pneumatic flue gas dryer the wet biomass is circulated with the flue gases and the moisture leaves the dryer with the flue gases [18]. In this study we assumed that flue gases from the refinery process can be cooled to 90 °C.

The air dryer is used as the main biomass dryer in all cases. The exception is the EF gasifier where flue gas from the torrefaction process is used to dry the biomass and where excess heat from the pyrolysis process is enough to dry the biomass.

Data for the drying technologies are taken from [18,23,33,34]. Electricity consumptions for the dryers are given in Table 3.

5.3.3. Pre-treatment technologies

In order to use the EF gasification technology, pre-treatment of the biomass may be necessary [35]. Two alternatives for pre-treatment have been used in this study.

Pyrolysis: A thermal decomposition of biomass, into liquid oil, gas and char, in absence of oxygen. Fast pyrolysis is one method where biomass is rapidly heated to 500 °C and high yields of pyrolysis oil can be achieved, up to 75wt% on a dry basis [36].

Torrefaction: A thermo-chemical treatment method at atmospheric pressure in absence of oxygen. The process is carried out at temperatures between 200 and 300 °C. The final product is a solid uniform product with very low moisture content. Studies by [37] show that torrefaction is a promising technology due to its high energy efficiency (94%). The energy yield varies, however, depending on torrefaction temperature [38].

Data for the pyrolysis process are taken from Rodin (2008) [23], in which the model is based on [39,40]. Data for the torrefaction process are taken from Bergman (2005) [41] and Van der Drift (2004) [42]. Key data for the processes are given in Table 4.

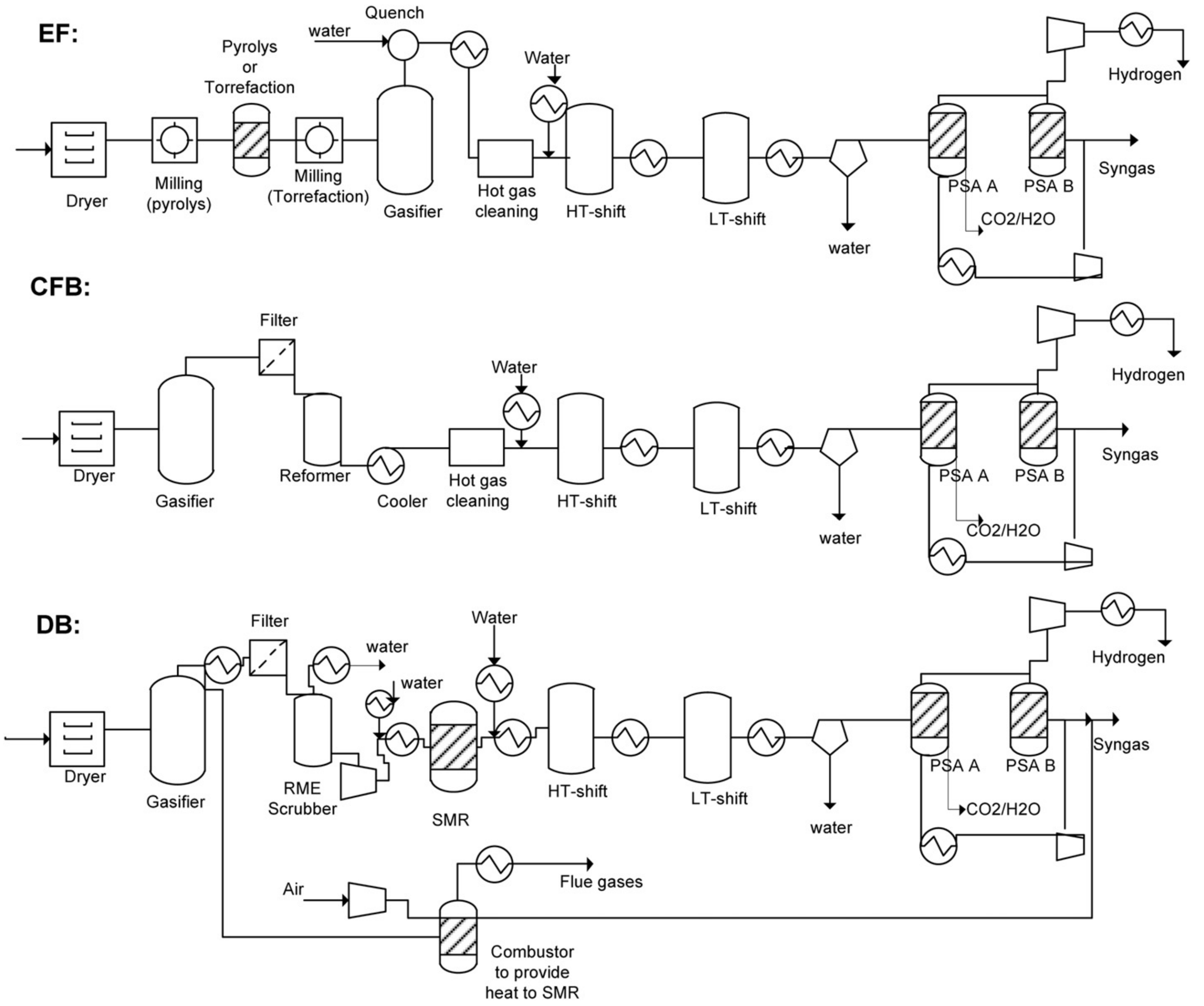

Fig. 3. Schematic overview of the BG concepts, from biomass drying to production of hydrogen.

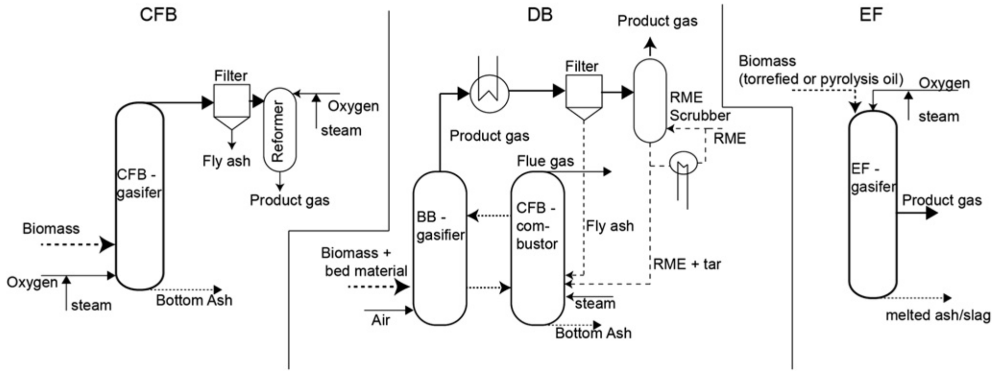

Fig. 4. The different gasifier steps simulated and provided by Eva Larsson at TPS.

Table 2
Feedstock composition.

	Ash content [%]	C [%]	H [%]	O [%]	N [%]	S [%]	Cl [%]	LHV [MJ/kg DS]
Biomass[a]	2.11	50.68	6.02	40.64	0.50	0.04	0.01	19.2
Pyrolysis oil[b]	0.15	56.23	6.48	36.67	0.39	0.08	0.001	21.7
Torrefied biomass	2.35	55.50	5.57	36.01	0.50	0.06	0.01	20.9

[a] Composition defined for a mixture of wood, bark and waste wood (from discussion with Eva Larsson at TPS [32]).
[b] Composition for the pyrolysis oil is taken from Rodin [23].

Table 3
Drying technologies and related electricity consumption.

Type of dryer	Electricity consumption [kWh/ton biomass (down to a moisture content of 10%]
Air dryer (Band dryer)	25.5 [33]
Steam dryer	36 [34]
Flue gas dryer	64 [34]

Table 4
Key data used for the pyrolysis and torrefaction process.

Pyrolysis process		
Pyrolysis oil (yield)	[%]	74
Pyrolysis coke (yield)	[%]	12.5
Pyrolysis gas (yield)	[%]	13.5
Moisture content (pyrolysis oil)	[%]	20
Energy content (yield)(biomass to oil)	[%]	84
Steam production	[MJ/kg dry BM][a]	0.8
Warm air production	[MJ/kg dry BM]	1.8
Torrefaction Process		
Mass (yield)	[%]	77[b]
Energy content (yield)	[%]	96[b]
Moisture content	[%]	3
Cooling demand	[MJ/kg dry BM]	0.4

[a] BM = Biomass.
[b] This efficiency is taken based on[42].

6. Methodology

The methodology used is based on the following methods and steps:

1. Simulation of BG and SMR steps to achieve energy balances
2. Pinch analyses of the refinery process, the SMR process and the BG processes to analyse the integration possibilities
3. Evaluation of CO_2 emissions using future energy market scenarios
4. Sensitivity analysis

6.1. *Simulation of the BG and SMR*

Models of the BG's syngas cleaning chain, starting from the syngas after the gasifier, and the SMR process are constructed in the optimising model tool Aspen Plus®. Using this tool, energy balances from the different cases were calculated to serve as inputs for process integration analyses of the total system, including the gasifier, drying, upgrading and cooling of the syngas, as well as the refinery process.

In order to get conformable input data for the BG upgrading simulations, all calculations on mass and energy balances for synthesis gas production from biomass in the different BG alternatives were prepared with the same biomass composition (except for the pyrolysis), see Section 5.3.1. The resulted syngas composition after each gasifier can be found in Table 5.

Table 5
Syngas compositions after the gasifier

	CFB[a]	DB[b]	EF[c]	EF[d]
C_2H_6 [%]	0–0	0.05–0.05	0.01–0.00	0–0
C_2H_4 [%]	0–0	1.58–1.53	0.02–0.01	0.01–0.01
CH_4 [%]	0.85–0.71	5.19–5.00	0.05–0.05	0.05–0.04
CO [%]	23.37–15.53	18.49–14.69	43.37–42.92	34.05–34.01
CO_2 [%]	14.98–16.78	9.25–9.68	9.08–9.25	12.29–12.16
H_2 [%]	29.83–24.88	24.91–22.13	25.86–22.47	25.05–21.18
H_2O[%]	27.95–39.30	37.94–44.39	16.49–20.18	27.52–31.55
N_2 [%]	2.86–2.66	1.81–1.80	4.7–4.67	0.69–0.69
Ar [%]	0.07–0.07	0.01–0.01	0.1–0.11	0.11–0.12
NH_3 [%]	0.06–0.05	0.40–0.38	0.28–0.28	0.19–0.19
H_2S [%]	0.01–0.01	0.02–0.02	0.02–0.02	0.03–0.03
BTX [%]	0.01–0.01	0.31–0.30	0.01–0.01	0.01–0.01
Tar [%]	0–0	0.04–0.03	0.01–0.01	0.01–0.01

[a] Including the steam reformer and with a biomass moisture content varying from 10% to 30%.
[b] Syngas out from DB with a biomass moisture content varying from 10% to 17%.
[c] EF with torrefied biomass with a gasification temperature varying from 1300°C to 1500°C.
[d] EF with pyrolysis oil with a gasification temperature varying from 1300°C to 1500°C.

Table 6 presents key data, input data and resulting balances for the different gasifiers as well as for the SMR, which is used as input to the Aspen® simulations. Data for the common upgrading steps are provided in Table 7.

6.2. *Pinch analyses*

Process integration opportunities are analysed using the pinch analysis methodology. In the process integration analysis, the pinch analysis methodology, which was first developed by Linnhoff and colleagues in the late 1970s, is used. A thorough description of the methodology can be found in several editions; one of the most recently updated is [45]. Pinch analysis enables the designer to identify energy targets that minimise the use of hot and cold utilities by maximising internal heat recovery in the process. Moreover, the curves constructed in the pinch analysis are used for identifying possible steam production, as well as opportunities for energy-efficient integration of energy-intensive process units, such as the drying of biomass.

Since both the refinery process and the BG process have large cooling demands, the pinch analysis in this paper is divided into two parts. The first part consists of a pinch analysis of the different BG concepts and the SMR. In this analysis the pinch analysis tool, so-called background/foreground analysis, is used to identify possible steam production. Included in the background analyses are the heating and cooling demand of the upgrading of the syngas from the gasifiers (illustrated as heat exchangers in Fig. 3) and the whole SMR process (same upgrading steps as for the syngas). The foreground includes data for steam production to the gasifiers and steam production to the refinery process. The results are presented

Table 6
Key data for the BG alternatives.

EF gasifier – torrefied biomass			
Temperature	1300–1500	°C	
Pressure	30	bar	
Moisture content torrefied biomass	3	%	
Biomass to gasifier	3.5–3.7	kg DS/s	
Steam to gasifier	0.52–0.58	kg/s	
Oxygen to gasifier	4.45–4.83	kg/s	
Gasification medium	Oxygen and Steam		
EF gasifier – pyrolysis oil			
Temperature	1300–1500	°C	
Pressure	30	bar	
Moisture content pyrolysis oil	20	%	[23]
Biomass to gasifier	3.6–3.8	kg DS/s	
Steam to gasifier	0.46–0.52	kg/s	
Oxygen to gasifier	5.20–5.66	kg/s	
Gasification medium	Oxygen and Steam		
CFB – gasifier			
Temperature	950	°C	
Pressure	30	bar	
Biomass moisture content of the feed to gasifier	10–30	%	
Biomass	3.9–4.3	kg DS/s	
Steam to gasifier and reformer	1.8–2.1	kg/s	
Oxygen to gasifier	4.28–5.15	kg/s	
Gasification medium	Oxygen and Steam		
DB – gasifier			
Temperature	900–1000	°C	
Pressure	1.4	bar	
Scrubber – RME	40	°C	
SMR	890	°C	[29]
Biomass moisture content of the feed to gasifier	10–17	%	
Biomass	4.2–4.4	kg DS/s	
Steam to gasifier & CFB combustor	2.1–2.2	kg/s	
SMR			
SMR – methane	860	°C	

in Section 7.1. For a more thorough description of the background/foreground analyses see [34,45].

The second part includes the studied refinery process. The aim of this analysis is to examine the cooling demand and possibilities to use excess heat for drying of the biomass. The pinch analysis of the studied refinery process is limited to include the cooling demand (e.g. streams cooled with utility) and the potential heat content of the flue gases. The included flue gases are assumed to be cooled to 90 °C. The analysis includes 85 streams, most of them are currently heat exchanged with the district heating system. The analysis also includes streams that currently are cooled with air (fans) and flue gas streams. The existing process-to-process heating network is assumed to be well constructed and accepted without further analysis. Therefore, the survey shows only available excess heat at different temperatures for the studied refinery. To determine whether this truly is waste heat, a complete pinch analysis of the existing process is necessary.

Table 7
Key data for the common upgrading steps.

Common steps for all processes			
Temperature to HT-shift	350	°C	[29]
Temperature to LT shift	260	°C	[29]
Hydrogen recovery PSA (B)	84	%	[29,43]
Overall hydrogen recovery	>90	%	[29,43]
Hydrogen production pressure	75	bar	[44]

6.3. *Evaluation of CO_2 emissions*

The CO_2 emissions from the studied system are evaluated in an expanded system. By an expanded system is meant that energy consequences outside the refinery are also considered in the analysis. It is assumed that the net energy streams entering or leaving the refinery affect the surrounding system; see Fig. 5. Electricity produced or used in the studied system affects the surrounding electricity system by decreasing or increasing the need for externally produced electricity. This system perspective is more thoroughly described by e.g. Andersson and Harvey (2007) [20] and Wetterlund et al. (2011) [21]. The CO_2 effect (ΔCO_2) of integrating BG with the refinery process is evaluated by comparison to integration of a conventional SMR and calculated according to Eq. 1:

$$\Delta CO_2 = CO_{2(\text{refinery+steam reformer})} - CO_{2(\text{refinery+biomass gasification})}[\text{kt } CO_2/\text{year}] \quad (1)$$

By using a number of different possible cornerstones of a future energy market, robust investments can be identified. The CO_2 effect is evaluated using future energy market scenarios developed by Axelsson et al. (2010;2009) [46,47] with two marginal producers of electricity:

- Scenario 1: Coal power plant (679 kg CO_2/MWh_{el})
- Scenario 2: Coal power plant with CCS (129 kg CO_2/MWh_{el})

The emissions related to the electricity production are compiled assuming an electrical efficiency of 0.51 for the coal power plant and an electrical efficiency of 0.40 for the coal power plant with CCS [46]. The combined well-to-gate and combustion CO_2 emissions for coal are set to 347 kg CO_2/MWh [46].

In this study, biomass is considered both as an unlimited and as a limited resource. When biomass is considered as a limited resource, sufficient biomass is not available to substitute for all fossil fuels in society. Consequently, alternative users of biomass are in this study assumed to be coal power plants, and 336 kg CO_2/MWh is allocated to the biomass user. The CO_2 emissions corresponding to alternative uses of biomass are based on avoided emissions for the fossil fuel that is replaced, hence, 336 kg CO_2/MWh corresponds to the CO_2 emissions related to the decreased use of coal (347 kg CO_2/MWh) minus the CO_2 emissions related to transportation of biomass (11 kg CO_2/MWh) (see [46] for a more thorough description). Under these assumptions, the biomass used for gasification into H_2 will decrease the biomass available for other applications.

The cases studied are:

Case A: Sufficient biomass is available, i.e., the usage of biomass is CO_2-neutral.

Case B: Biomass is considered to be a limited resource, i.e., the usage of biomass is allocated 336 kg CO_2/MWh.

6.4. *Sensitivity analysis*

The choice of drying technology has a potential influence on the energy balance for the BG processes. To study how the different drying technologies affect the total CO_2 balance for the refinery, steam drying and flue gas drying are evaluated in comparison with air drying for the CFB case.

A base assumption for the EF gasifiers in this study is a gasification temperature of 1300 °C. The alternative with a gasification temperature of 1500 °C for the EF gasifiers is included in the sensitivity analysis.

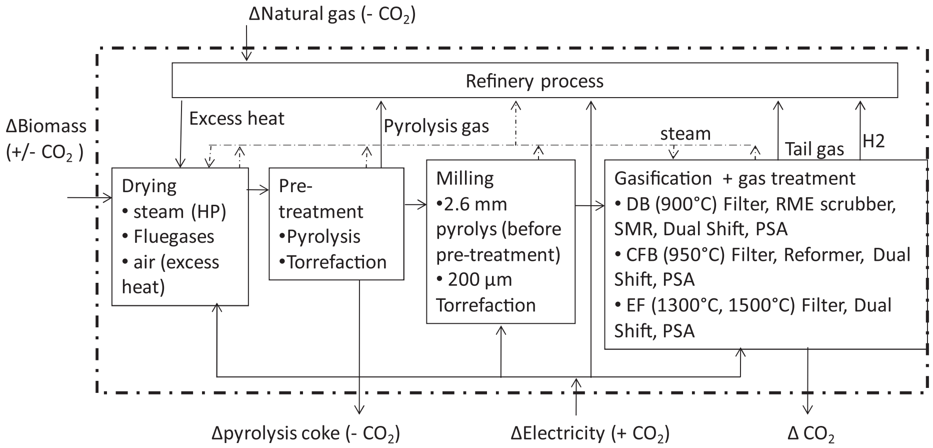

Fig. 5. The evaluated system – boundaries and assumptions. Only streams that will change in comparison with the reference case (refinery + SMR) are included. The dashed lines in the figure represent streams of steam.

Previous studies [29,48,49] indicate that the optimum moisture content for the gasification process is around 10–20%. However, higher moisture content requires less drying and, hence, less energy. To study how the moisture content affects the CO_2 balance, the moisture content is increased for the biomass to the CFB process from 10% to 20%, and 30%. Only two levels of moisture content for the DB process are used, 10% and 17%. This is due to the fact that high moisture content does not favour the $H_2 + CO$ yield, which already is low in the DB process compared to the yield in the CFB process.

In this paper, alternative use of biomass is assumed to be co-firing of biomass in coal power plants. In order to study how the change of alternative usage of biomass affects the CO_2 consequences of the different BG concepts, the alternative biomass user is changed from coal power plant to DME production (which could be a future alternative producer of biofuels). Since CO_2 emissions from electricity production vary depending on marginal producer of electricity the biomass user has in this case been allocated 118 kg CO_2/MWh and 152 kg CO_2/MWh, depending on marginal electricity producer. The corresponding CO_2 emissions to the use of biomass for DME production are based on avoided emissions for the fossil fuel replaced (in this case diesel). The values 118 kg CO_2/MWh and 152 kg CO_2/MWh corresponds to the CO_2 emissions related to the decreased use of diesel (185 kg CO_2/MWh) minus the CO_2 emissions related to well-to-gate emissions to the DME plant, e.g. transportation emissions, (24 kg CO_2/MWh) and minus the CO_2 emissions related to the electricity use in the DME plant (42 kg CO_2/MWh and 8 kg CO_2/MWh). For a thorough description see [46].

The stand-alone DME production is chosen since it is well examined in the literature. A future integrated DME production is more likely, but is not chosen as an alternative since this is ongoing research and the results are highly dependent on the system boundaries (see e.g. [22]). Table 8 shows the energy balance for the DME production plant. For a detailed and thorough description of the DME Scenario, see [46].

Table 8
Key figures for the DME production plant.

DME output rate	131	[MW]
Electricity input	12.5	[MW]
Wood fuel input	200	[MW]

7. Results and analysis

The first two research questions in this paper are addressed together under Section 7.1. The last question is addressed separately under Section 7.2. Results from the sensitivity analysis are presented in Section 7.3.

7.1. Pinch analysis and energy balances

The pinch analysis result of the future refinery cooling demand indicates large amounts of excess heat. Most of the excess heat can be found at temperatures less than 100 °C; see Fig. 6. However, 74 MW can be found at temperature levels above 100 °C and 38 MW at temperature levels above 150 °C. The air drying of biomass from, for example, 50% to 10% moisture content requires (in absolute terms) 13 MW for the CFB process and 14 MW for the DB process, which can, with large margin, be taken from the refining process. Drying of the biomass in the EF cases is made with excess heat from the pre-treatment processes.

Both the SMR and the BG process have large cooling demands. The syngas flow is generated at high temperature levels and can be used for steam production. Steam produced from the SMR or the BG processes will decrease the load of the refinery boilers and save imported fuel (natural gas). To analyse the amount of steam that could be produced, background/foreground curves were constructed for the BG and for the SMR processes. The background curves include stream data for the upgrading steps, starting with the syngas after the gasifier or the SMR. The foreground curves include steam production of required steam for the gasification processes, steam production of MP and LP steam to the refinery. For the DB case, also the flue gas stream from the connected combustor is included in the foreground curve. The torrefied biomass needs to be cooled after the torrefaction process and, hence, included in the foreground curve for the EF (torrefaction) process. Fig. 7 shows the background/foreground of the BG alternatives and, hence, the amount of produced steam.

Key results of the evaluation of the energy balance at the refinery with an SMR or BG can be viewed in Table 9.

The CFB process is the most efficient BG process (regarding MW H_2/MW dry biomass). This can be explained by the facts that no pre-treatment is necessary except for drying of the biomass, and that the syngas has a higher H_2 content compared to the syngas from the DB gasifier. The largest steam production is obtained from the EF gasifier using pyrolysis oil. The high steam production can

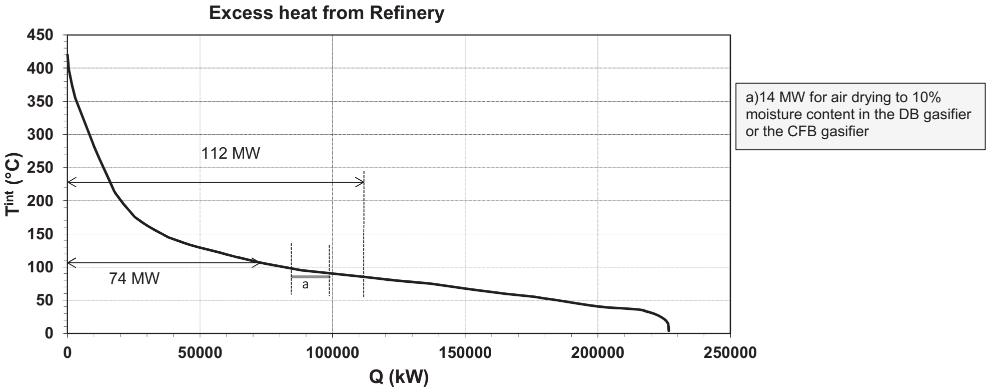

Fig. 6. Excess heat from the studied refinery including the energy demand for drying biomass to 10% moisture content in the CFB or the DB processes.

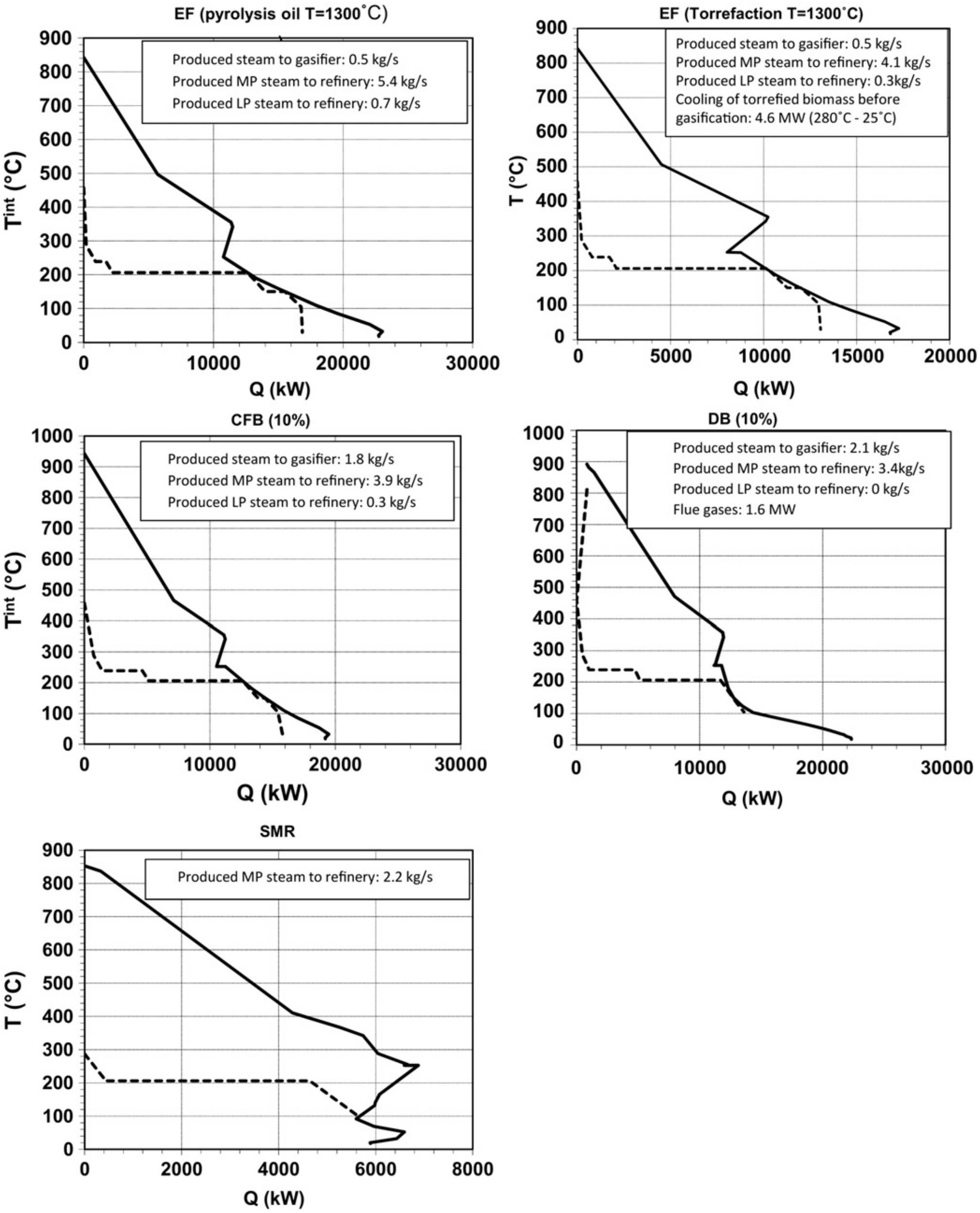

Fig. 7. Background/Foreground curves for the different BG alternatives and the SMR. The left curve (dotted) in each diagram represents the foreground curve and the right curve in each diagram represents the background curve. Included in the foreground curve are also the preheating and superheating of the feed water.

Table 9
Results for the refinery after integration with an SMR or a BG.

	SMR	EF (pyrolysis oil)	EF (torrefied biomass)	CFB 10%	DB 10%
Crude oil feed [ton/day]	6.0	6.0	6.0	6.0	6.0
H_2 production[a] [m^3(n)/h]	16000	16,000	16,000	16,000	16,000
$El_{consumption}$ [MW]	19.4	26.3	27.8	22.7	22.1
NG to SMR [MW]	59.5	–	–	–	–
NG to boilers and process heaters [MW]	80.1	49.1	71.3	69.3	76.8
Dry biomass [MW]	–	104.0	86.4	74.3	80.1
SMR and gasifier efficiency [MW H_2/MW fuel in]	0.81	0.46	0.56	0.65	0.60
MP production [ton/h][b]	7.8	32.2	14.7	14	12.3
LP production [ton/h][b]	–	2.6	1.2	0.9	–
Tail gas [MW]	–	2.8	2.7	5.5	–
Pyrolysis gas [MW]	–	7.8	–	–	–
Excess heat [MW][c]	184.0	188.9	187.3	186.5	189.5
Fossil CO_2 emissions[d] [ton/h]	62	40	46	46	49

[a] Hydrogen production from SMR or BG (total production is 30,000 Nm^3/h).

[b] Steam production from the SMR or BG.

[c] Excess heat above 55 °C.

[d] These emissions are total emissions related to the combustion of fuel on-site the refinery. The analysis below also includes the CO_2 emissions from electricity generation outside the refinery gates.

mainly be explained by the fact that MP steam is produced during the pyrolysis pre-treatment. Moreover, the large reduction in natural gas demand in this case is due to the large steam production, but also due to the fact that pyrolysis gas is formed as a by-product during the pyrolysis process of the biomass and is used in the refinery process.

When more hydrogen is produced at the refinery, there will be an increase in electricity import. In all BG gasifiers, except from the DB gasifier, electricity is used for oxygen production. Electricity is also used in the pressurizing of the biomass, in the drying of the biomass, and in the compression of the hydrogen. The high electricity consumption for the EF (torrefied) process is due to a high electricity demand during the milling and pressurizing of the torrefied biomass. The DB gasifier does not require any oxygen production, but has larger electricity demand of the compressors due to higher content of inert gases (N_2).

7.2. CO_2 consequence of implementing a BG gasifier for hydrogen production compared to an SMR

Figs. 8 and 9 show that implementing biomass gasification for hydrogen production in a refinery does not necessarily entail a reduction in global CO_2 emissions. Instead the global CO_2 effect is influenced by the assumption of the biomass availability (e.g. whether biomass should be seen as an unlimited or limited resource).

The results of the evaluation of the CO_2 effect, when assuming sufficient availability of biomass in the future (Case A), are shown in Fig. 8. Negative values correspond to a decrease of global CO_2 emissions compared to the reference case, an SMR. Fig. 8 shows that implementation of hydrogen production through gasification of biomass will decrease the CO_2 emissions compared to the reference case. The EF gasification with pyrolysis oil has the largest reduction of CO_2 emissions. In Case A, the EF gasification with pyrolysis oil benefits from the extra production of MP steam, pyrolysis gas and pyrolysis coke, which leads to CO_2 emissions reduction. It is important to note that the larger production of steam and pyrolysis gas is due to a higher biomass demand in the process, as a consequence of the pre-treatment, and the fact that the H_2 production is the base.

When the CO_2 effect from the electricity that is used is small (Scenario 2 with coal condensing power plants with CCS as marginal electricity producer), H_2 production through DB gasification gives the smallest decrease of CO_2 emissions. The DB gasifier produces the smallest amount of steam, and therefore has the smallest reduction in CO_2 emissions. If instead a large CO_2 effect from the electricity that is used is obtained, the EF gasification gives the smallest decrease of CO_2 emissions. In this case the marginal electricity producer is a coal condensing power plant without CCS. The milling and pressurizing of the torrefied biomass is very electricity-consuming, which affects the CO_2 emission balance adversely. The CO_2 emissions reduction is greatest in the scenario with low-emitting marginal production (Scenario 2).

If biomass is considered a limited resource (Case B) the results show a net increase of CO_2 in all cases compared to the reference case; see Fig. 9. As discussed previously, the biomass import to the refinery could in this case have been replacing coal in coal

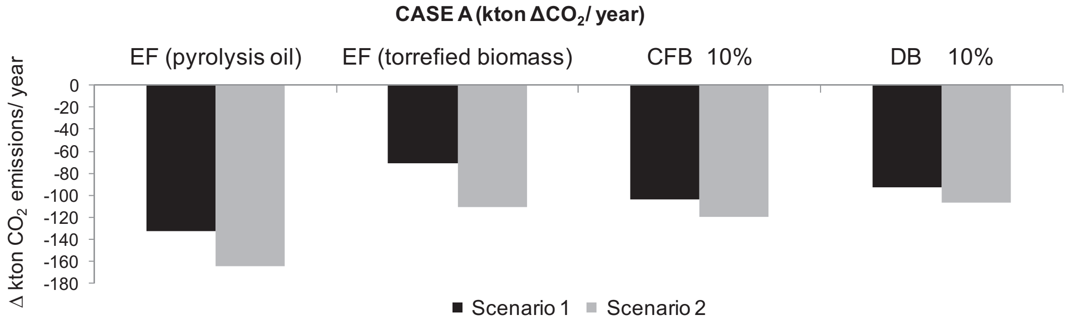

Fig. 8. The effect on global CO_2 emissions of the different BG concepts in comparison with an SMR when biomass is considered an unlimited resource.

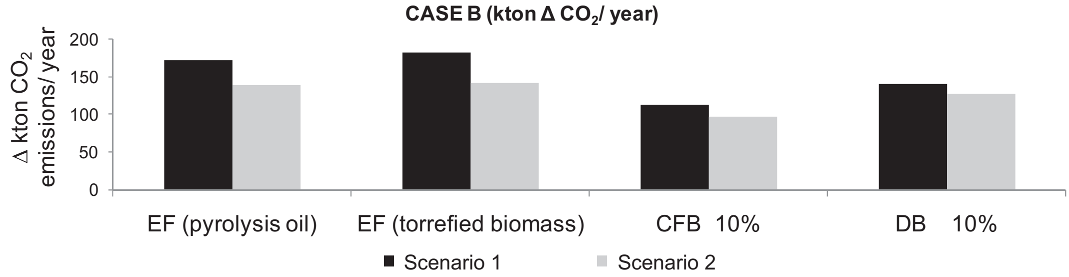

Fig. 9. The effect on global CO_2 emissions of the different BG concepts in comparison with an SMR when biomass is considered a limited resource.

condensing power plants, and CO_2 emissions are therefore allocated to the use of biomass, equivalent to the combustion of coal (336 $kgCO_2/MWh_{fuel}$). Compared to the allocated CO_2 emissions to the biomass, the natural gas use in the SMR has lower CO_2 emissions.

Fig. 9 shows that hydrogen production through CFB gasification achieves the smallest increase of CO_2 emissions. In this case, the CFB gasification benefits from requiring the smallest amount of biomass. The EF gasifiers has the largest CO_2 emissions, which is due to the high biomass demand for the EF (pyrolysis) case and a combination of high biomass demand and high electricity use in the EF (torrefied) process. However, due to the large electricity demand, the EF (torrefied biomass) emits less compared to the EF (pyrolysis) when the CO_2 effect from electricity use is lower.

7.3. *Sensitivity analysis*

Figs. 10–13 show the results of the sensitivity analysis. When changing the drying technology from air drying to steam drying, the global CO_2 emissions are affected negatively. The negative CO_2 effect for the change from air dryer to steam dryer is due to the fuel increase that is necessary if a steam dryer should be used. The other alternatives, air and flue gas drying, can use already available energy from the process (flue gases and excess heat). The small difference in global CO_2 emissions between air drying and flue gas drying is due to a higher electricity demand in the flue gas drying procedure.

The assumption regarding the gasification temperature in the EF gasifier has little effect on the CO_2 balance. From Fig. 11 it can be seen that only small changes are made in the CO_2 emissions.

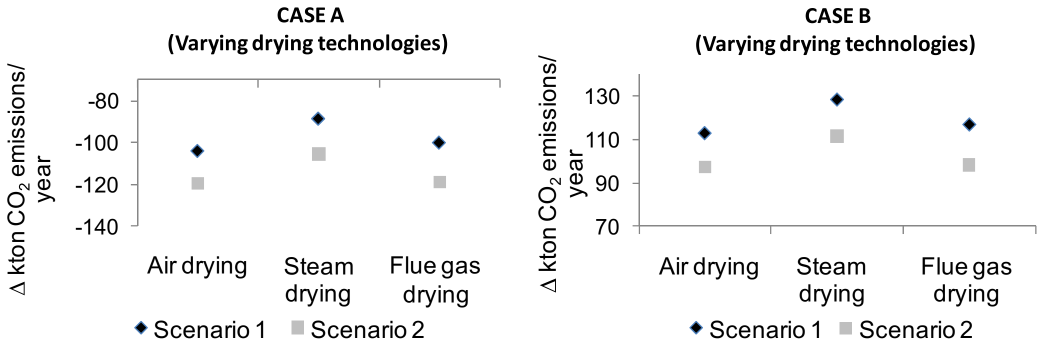

Fig. 10. Comparison of the CO_2 effect when using different drying alternatives.

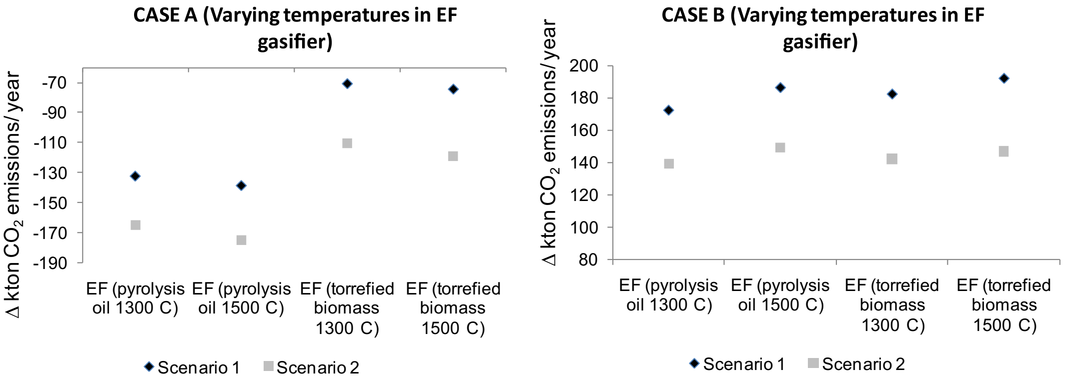

Fig. 11. Comparison of the CO_2 effect when using different gasification temperatures.

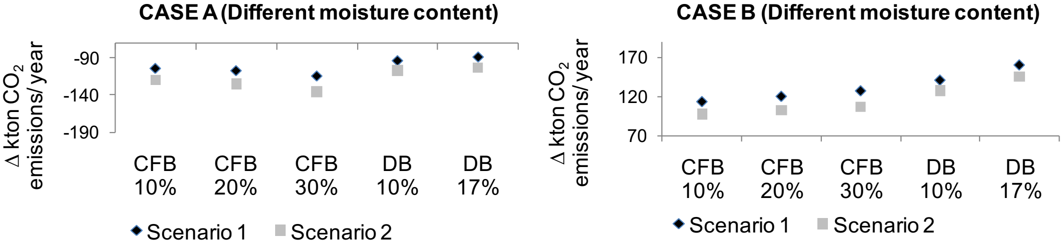

Fig. 12. Comparison of the CO_2 effect when using different levels of moisture content. Initial moisture content of the biomass is 50%.

When changing the moisture content of the biomass to the gasifier, the global CO_2 emissions change moderately. In Case A, biomass with higher moisture content has a positive effect, which can be explained by a larger syngas flow that generates more excess heat for steam production for the refinery process.

In Case B, the moisture content has a negative effect on the global CO_2 emissions. In this case the increase of biomass demand (on dry basis) has a larger effect on the global CO_2 emissions compared to the increase in steam generation related to a larger flue gas stream, see Fig. 12.

A high moisture content requires more energy to evaporate the water. This energy is taken from the gasification process, and a syngas flow with lower energy content (lower yield of H_2 and CO) is obtained. At the same time, high moisture content is favourable for the water gas shift reaction, which occurs during gasification. Consequently, from the calculations with different moisture content provided by TPS, it can be seen that a higher moisture content of the biomass indicates a lower yield of H_2 and CO (vol.%), see also Table 5. But it also shows that, as the moisture content increases, the H_2/CO yield increases, which indicate that the water gas shift reaction drives the reaction towards more hydrogen. However, the heating value of the syngas decreases with increased moisture content, and the higher moisture content leads to a higher demand for dry biomass, which makes a process with high moisture content less efficient ($MW_{H2}/MW_{\text{dry fuel in}}$). In this case the biomass can be dried using more "low-value" heat for drying, e.g. excess heat from the process.

Further aspects, besides CO_2 emissions, must also be considered when evaluating the impact of the moisture content. High moisture content decreases the yield of the desirable product and, at the same time, increases the size of the equipment as well as increasing the primary energy demand, and should therefore not be seen as an aim of process design.

Fig. 13 shows that the assumptions regarding the alternative user of biomass has a large impact on the CO_2 consequence of BG at the refinery. In this figure the alternative user of biomass is DME production. The results show a decrease of global CO_2 emissions which can be compared to the increase of global CO_2 emissions in Fig. 9, where the alternative biomass user is coal condensing power plants. If the alternative user of biomass is DME production, less CO_2 emissions are allocated to the biomass use, which results in a decrease of CO_2 emission for the production of hydrogen through BG compared to SMR. The only exception is EF (torrefied biomass), which due to a large electricity demand has an increase of CO_2 emissions in Scenario 1.

8. Discussion

If biomass is not associated with any CO_2 emissions, BG in the refinery industry could be an alternative for CO_2 reduction compared to an SMR. If, however, biomass is considered limited, all cases show an increase in CO_2 emissions. In this situation, biomass is more CO_2-efficiently used for co-firing in coal plants. Consequently, the choice of alternative use of biomass will have a large impact on the resultant CO_2 effect. If we had assumed the alternative biomass user to be biofuel producer (e.g. DME) instead of coal condensing power plants, the CO_2 effect from gasifiers would have been more favourable. In this paper the results show that most alternatives give larger CO_2 reduction than DME production. The two alternative biomass users can be seen as two extreme cases, which are based on two well-defined processes. The fossil fuel emissions replaced by integrated production of DME (or other biofuels) will lie between these cases, and will most probably make the biomass gasification to hydrogen in oil refineries less favourable than alternative use of biomass.

The EF of pyrolysis oil requires more biomass (on dry basis) but generates more by-products than the CFB case. Therefore, when no emissions are associated with the biomass, the EF of pyrolysis oil generates the largest CO_2 reduction. The CFB gasification, however, requires less biomass (on dry basis) and,

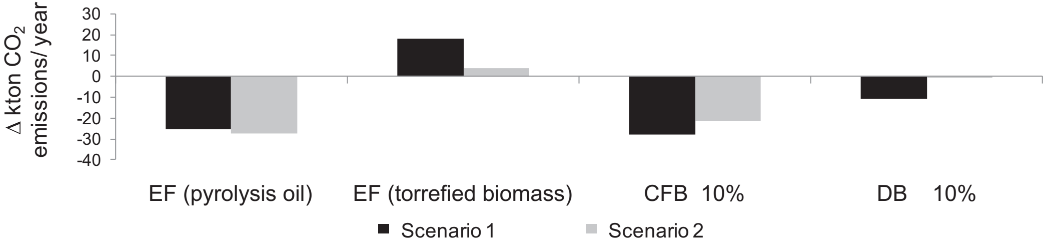

Fig. 13. The effect on global CO_2 emissions for the different BG concepts in comparison with an SMR when biomass is considered a limited resource and the alternative biomass user is DME production.

therefore, generates less CO_2 if biomass use is associated with CO_2 emissions.

The final choice of whether to integrate a BG in a refinery is dependent on several more parameters, such as: investment costs, logistics for a new feedstock, development of the BG processes, and market prices for heat, electricity, biomass and emissions. The production of sufficient hydrogen is relatively small (ca. 100 MW_{dry} biomass) in this paper and could be hard to make profitable, due to high investment costs. Sakar and Kumar [14] show an optimum size for biohydrogen production of ca. 1000 MW. Their study is of a stand-alone plant and shows that the transportation costs for hydrogen are almost 50% of the total costs, which could make a smaller plant more cost-effective if located at the refinery. Moreover, Sakar and Kumar do not take any integration advantages into consideration, which could have reduced the costs additionally. However, a comparison indicates that a larger plant than the one studied in this paper might be necessary to make the hydrogen production profitable. Therefore, this would probably be a more interesting option for larger refineries with larger hydrogen demands.

Another parameter to consider is the availability of the feedstock to the BG compared with the SMR. The H_2 production requires high accessibility; otherwise spare capacity is required.

In the PSA process for the hydrogen separation, an almost clean CO_2 stream is leaving the adsorption bed. In this paper, this stream is assumed to be vented to the air. However, if the refinery is located in regions with future infrastructure for transportation of CO_2 to storage, the almost clean CO_2 stream leaving the PSA could be captured. This would decrease the CO_2 emissions for both the SMR and the BGs significantly and hence reduce the total emissions.

In this paper it is assumed that excess heat is available and not used for district heating. But if district heating is available, the effect must be investigated, and will probably be positive for the EF gasifiers since in that case drying is not using excess heat from the refinery process. The torrefaction process is less studied than the pyrolysis process and is currently under development. In this paper, less information was found about the torrefaction process. Therefore, in future studies the integration possibilities for the torrefaction process need to be studied in more detail. Also the BG technologies are currently under development, and the final design and best technology are still being developed. This paper does not include any optimisation of the biomass processes or the SMR process, but the results do indicate the CO_2 effect of integrating a BG compared to an SMR, given different prerequisites.

9. Conclusions

Assumptions regarding systems surrounding the refinery and biomass availability will affect CO_2 emissions balance for integrating a BG for H_2 production in a refinery. In this paper it is shown that if biomass is changed from being considered unlimited to a limited resource (with coal power plant as alternative user), all BG concepts will change from a decrease to an increase of CO_2 emissions compared with a conventional SMR. Generally the EF (pyrolysis oil) gasification is favoured in cases when biomass is considered unlimited, since this process has a high steam generation as a consequence of large biomass use. CFB gasification is favoured in cases when biomass is considered a limited resource (i.e. CO_2 emissions are allocated to the biomass user), due to the lowest biomass demand (on dry basis). This paper also shows that the choice of alternative use of biomass will significantly affect the result and change the impact on the CO_2 emission balance, compared with an SMR, from an increase to a decrease of CO_2 emission. It is shown that H_2 production at a refinery gives less CO_2 reduction than using biomass in coal power plants, but compared to DME production biomass is more efficiently used for H_2 at a refinery.

Acknowledgement

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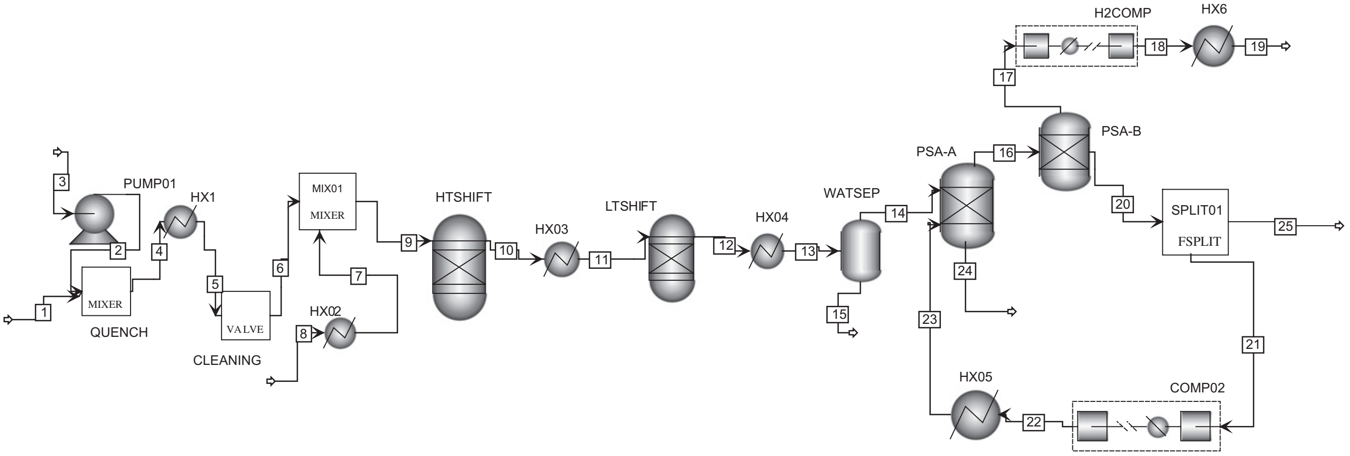
Appendix

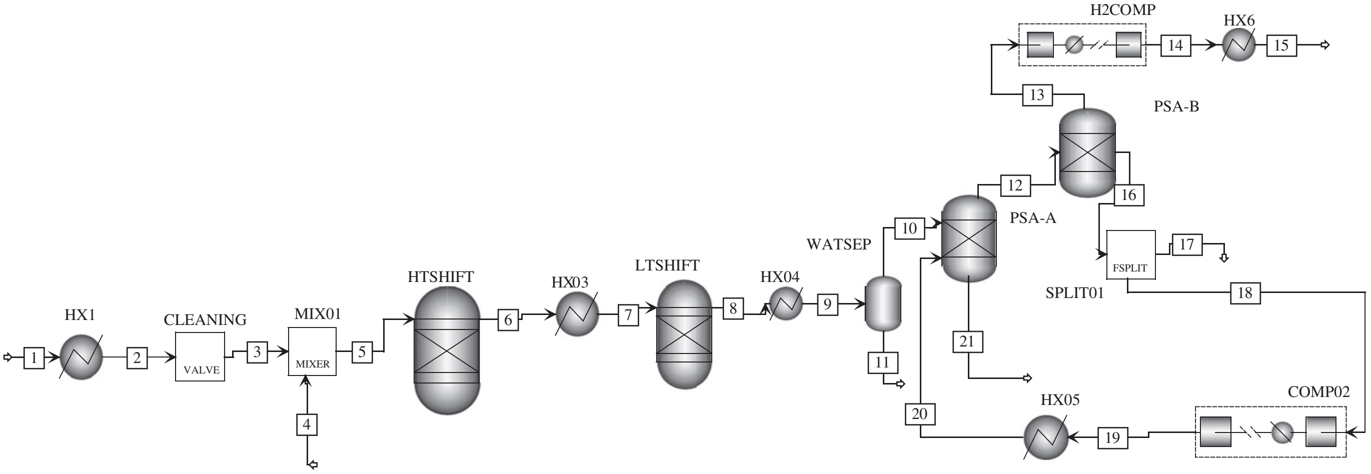
In the Appendix, results from the simulations from the upgrading steps are found.

The EF gasifier:



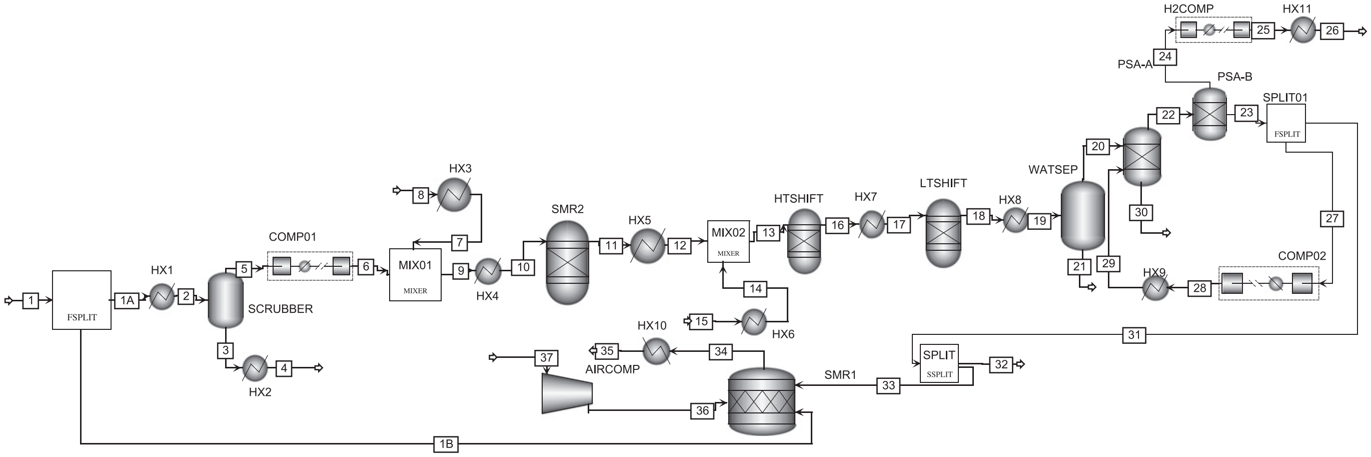
	T [°C]	P [bar]	Flow [ton/h]		T [°C]	P [bar]	Flow [ton/h]		T [°C]	P [bar]	Flow [ton/h]
Pyrolysis (T=1300 °C)											
1	1300	30	26.5	10	23.4	504.1	43.9	19	73.5	25	1.5
2	25	30	5.4	11	22.9	260	43.9	20	1.3	39.7	3.2
3	25	1	5.5	12	22.4	260	43.9	21	1.3	39.7	2.6
4	853	29.5	32.0	13	21.9	40	43.9	22	22	196	2.6
5	350	28.9	32.0	14	21.9	40	28.0	23	21.6	40	2.6
6	349	23.9	32.0	15	21.9	40	15.9	24	1.3	39.7	25.9
7	350	33.8	12.0	16	21.2	39.7	4.7	25	1.3	39.7	0.6
8	16	34.5	12.0	17	20.8	39.7	1.5	26			
9	23.9	345.3	43.9	18	75	116	1.5	27			
Torrefaction (T=1300 °C)											
1	1300	30	23.1	10	23.4	513.4	45.5	19	73.5	25	1.5
2	25	30	4.3	11	22.9	260	45.5	20	1.3	39.7	9.0
3	25	1	4.3	12	22.4	260	45.5	21	1.3	39.7	7.2
4	853	29.5	27.4	13	21.9	40	45.5	22	22	195	7.2
5	350	28.9	27.4	14	21.9	40	28.3	23	21.6	40	7.2
6	349	23.9	27.4	15	21.9	40	17.2	24	1.3	39.7	25.0
7	350	33.8	18.2	16	21.2	39.7	10.4	25	1.3	39.7	1.8
8	16	34.5	18.2	17	20.8	39.7	1.5	26			
9	23.9	345.6	45.5	18	75	116	1.5	27			

The CFB gasifier (10% moisture content of the biomass):



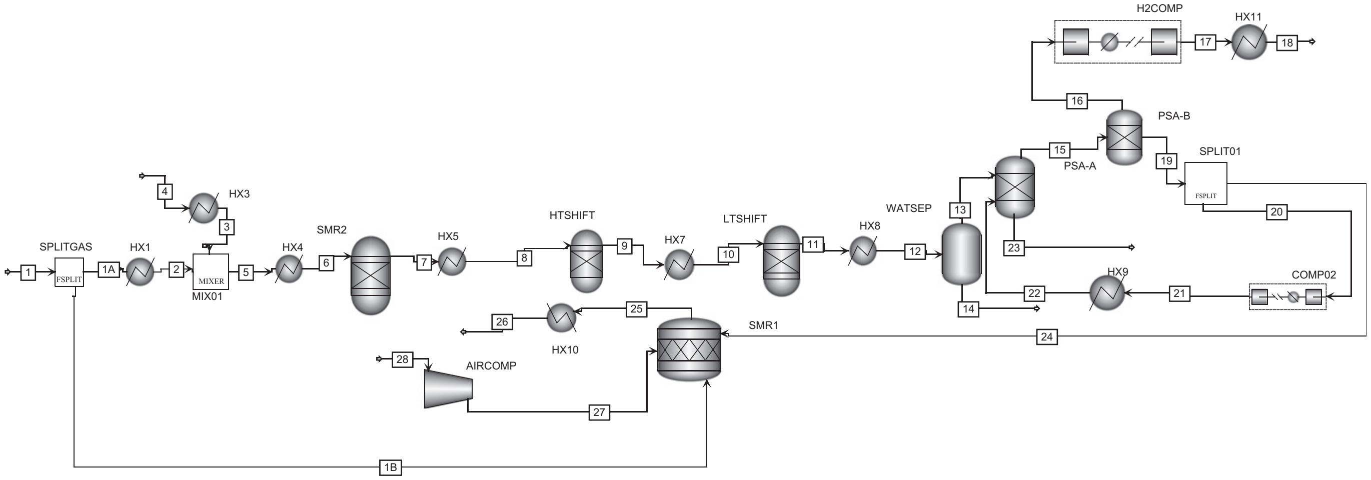
	T [°C]	P [bar]	Flow [ton/h]		T [°C]	P [bar]	Flow [ton/h]		T [°C]	P [bar]	Flow [ton/h]
1	950	29	28.3	8	260	22.0	39.2	16	39.8	1.3	8.8
2	350	28.4	28.3	9	40	21.5	39.2	17	39.8	1.3	1.8
3	349.3	23.4	28.3	10	40	21.5	27.0	18	39.8	1.3	7.0
4A	16	34.5	10.9	11	40	21.5	12.2	19	188	22	7.0
4	350	33.8	10.9	12	39.8	21.2	10.2	20	40	21.5	7.0
5	345	23.4	39.2	13	39.8	20.8	1.5	21	39.8	1.3	23.8
6	474	22.9	39.2	14	116	75	1.5				
7	260	22.5	39.2	15	25	73.5	1.5				

The DB gasifier (10% moisture content of the biomass):



	T [°C]	P [bar]	Flow [ton/h]		T [°C]	P [bar]	Flow [ton/h]		T [°C]	P [bar]	Flow [ton/h]
1	900	1.4	22.3	12	350	14.7	18.8	25	121	76.5	1.5
1A	900	1.4	21.4	13	350	14.7	30.3	26	25	75	1.5
1B	900	1.4	0.9	14	350	14.7	11.5	27	39.9	1.3	5.3
2	120	1.4	21.4	15	20	15	11.5	28	131	13.42	5.3
3	40	1.3	7.3	16	478	14.2	30.3	29	40	13.2	5.3
4	25	1.3	7.3	17	260	13.9	30.3	30	39.9	1.3	17.1
5	40	1.3	14	18	260	13.4	30.3	31	39.9	1.3	1.3
6	60	15.8	14	19	40	13.2	30.3	32	39.9	1.3	0.5
7	250	15.8	4.7	20	40	13.2	19.9	33	39.9	1.3	0.8
8	15	16.1	4.7	21	40	13.2	10.4	34	890	1.3	13.7
9	143	15.8	18.8	22	39.9	12.8	8.0	35	100	1.3	13.7
10	860	15.5	18.8	23	39.9	1.3	6.6	36	45	1.3	12.0
11	890	15	18.8	24	39.9	12.5	1.5	37	15	1.3	12.0

The SMR:



	T [°C]	P [bar]	Flow [ton/h]		T [°C]	P [bar]	Flow [ton/h]		T [°C]	P [bar]	Flow [ton/h]
1	10	28	4.4	9	418	25.4	17.4	19	39.7	1.3	5.5
1A	10	28	4.0	10	260	24.4	17.4	20	39.7	1.3	4.4
1B	10	28	0.4	11	260	24.4	17.4	21	174	24.41	4.4
2	350	27.4	4.0	12	40	23.9	17.4	22	40	23.9	4.4
3	15	28	13.4	13	40	23.9	11.1	23	39.7	1.3	8.5
4	250	27.4	13.4	14	40	23.9	6.3	24	39.7	1.3	1.1
5	281	27.4	17.4	15	39.7	23.5	6.9	25	860	1.3	23.7
6	830	26.9	17.4	16	39.7	23.2	1.5	26	140	1.3	23.7
7	860	26.4	17.4	17	99	76.5	1.5	27	45	1.3	22.2
8	350	25.9	17.4	18	25	75	1.5	28	15	1	22.4

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